The Effect of Responsive Demand in Domestic Sector on Power System Operation in the Networks with High Penetration of Renewables

V.Hamidi, F.Li *Member IEEE*, F. Robinson *Member IEEE*

Abstract—In this paper, the amount of dispatchable responsive demand from domestic sector with different methods of charging has been evaluated and the benefits of responsive demand in order to increase the security, reducing the emissions and production cost in an intermittent system has been presented. Additional benefit; the value of wind is also demonstrated. The quantification was performed on the IEEE 30 busbar system through Security Constrained Unit-Commitment (SCUC) as assessment tool.

Index Terms— **Responsive Demand, Renewable Energy, Security Constrained Unit-Commitment, Demand Side Management, Dynamic Demand**

I. Introduction

With increasing fuel prices and environmental concerns, the government in the UK has commissioned research on renewable energy applications with the consideration of diversifying energy sources. Electricity generation companies are obliged to satisfy Renewable Obligation (RO) policies. RO requires licensed electricity suppliers to obtain a specific and annually increasing percentage of the electricity they supply from renewable sources. The target for the UK is 10% of total electricity from renewables for 2010, and subsequently rising to 15.4% for 2015–2016 [1]. Since the cost of wind turbine generators and generation cost have been reduced to a great extent and the UK is among one of the windiest countries in Europe, integration of windfarms is economically and environmentally attractive in windy regions and there is widespread public support for them. The prospectus for wind industry will change and they may become among major power production sources in near future [2].

Renewables in general can displace conventional plants. National Grid Company; the UK main system operator, has estimated that 8,000 MW of wind power can displace around 3,000 MW of conventional plant. Besides; increasing the renewables (in particular wind) will makes it easier to meet the renewable obligation as it is very unlikely that all the windfarms in a country are out of order at the same time [16].

However, the current penetration of renewables and the intermittency and diffuse nature of wind energy creates difficulty in easily utilizing them. On the other hand network limits will further push these issues by problems such as network congestions in transmission lines or voltage rise in busbars in case they may not be fully dimensioned to accommodate additional large scale windfarms. These problems requires subsequent changes in conventional methods of operating the power system and additional means such as providing extra reserve or backing up wind resources with conventional plants, energy storage devices [4], or using [1]FACTS devices to mitigate transmission congestion.

It is known that demand can contribute on lessening the issues of power system. Demand Side Management (DSM) programmes since 1960-70's with the aim of reducing the dependency on fossil fuels and saving the energy have been practicing almost in all countries.

DSM mainly by reducing the peak demand, filling the demand curve valleys, strategic load growth, having more flexible types of load and shifting the load aims to [5, 20]:

1. Reduce price volatility/flattening spot prices;
2. Improve system security and reducing the risk of black-outs;
3. Reduce network congestion;
4. Delay construction of additional generation, and/or grid and network upgrading;
5. Reduce greenhouse gas emissions;
6. Improve market efficiency by enhancing consumers' ability to respond to changing Prices.

Currently major DSM programmes which aim to control the load in the UK included:

1. Load Shifting Methods (Economy 7 and Economy 10);
2. Ripple Controllers;
3. Energy Storage Devices.

DSM methods may not diminish the issues concerning intermittency; i.e. having lower peak load may facilitate reducing the need for utilization of peaker units to serve the demand but in case of loosing the power they are not the

Vandad Hamidi (Email: V.Hamidi@bath.ac.uk), Furong Li (Email: F.Li@bath.ac.uk) and Francis Robinson (Email: F.V.P.Robinson@bath.ac.uk) are with centre for sustainable power Distribution, University of Bath. Bath. UK. BA27AY

[1] Flexible Alternating Current Transmission System device is used to enhance controllability and increase power the transfer capability of the network.

solution. On the other hand as renewables are to be integrated mostly in remote distances where network is also limited to accommodate the extra power, therefore need to reinforce the network may also add on top of intermittency to transport the extra power from renewables.

Responsive Demand (Dynamic Demand) refers to the reduction of customer energy usage at times of peak usage or contingency in order to help addressing system reliability, reflect market conditions and pricing, and support optimization or network reinforcement deferral. In Renewable systems where power supplied through intermittent plants has fluctuations over the time, having such demand could help to cover power shortage. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling. Responsive demand as one of the DSM programmes has been used in power system since 1960's where ripple controllers had been installed with the intention of reducing the energy consumption of water heating units as one of the direct load management methods [6]. Recently new type of responsive demand has been introduced to provide ancillary services such as spinning reserve.

There are two major categories of responsive demand [7]:

1. Price-based demand; such as response real-time pricing (RTP), critical-peak pricing (CPP) and time-of-use (TOU) tariffs, give customers time-varying rates that reflect the value and cost of electricity in different time periods.

2. Incentive-based demand response programs pay participating customers to reduce their loads at times requested by the program sponsor, triggered either by a grid reliability problem or high electricity prices.

Many literatures have previously looked into this subject [7, 8, 9, 10, 11 and 12]; addressing the benefits of responsive demand to power system stability and operation. But none of these researches have been carried out in a system with high penetration of renewables where balancing between load and power may become an issue and in order to lessen this problem, operational parameters may change.

In this paper; section II first addresses the aggregation method of domestic demand in order to quantify the capable loads which could become responsive, section III looks into our assessment tool; security constrained unit-commitment and briefly explains the constraints which needs to be considered in a real generation scheduling process, section IV presents our test system and the details of all generation units; network and windfarms power output characteristics. And finally results are shown for different demand; single tariff or Economy 7, and the additional benefits of responsive demand are presented.

II. Domestic Demand Aggregation

Power demand in domestic sector of different networks has diverse patterns depending on socio-economic situation of each society. Direct factors such as energy management programs also change the load demand pattern. Different types of load have the capability of becoming responsive; those with passive mode of operation; such as fridge or air conditioner. Passive mode of operation an electric appliance could be understood as it is known that demand for electricity is indirect and consumers actually demand the services provided by the electricity rather than the electricity itself. Therefore passive demands are those which minor interruptions in their mode of operation do effect on consumers overall satisfaction of delivery of the electricity service [13].

The reason of choosing domestic sector for most of the direct load management programs is that domestic demand has more flexibility and loads in this area are less critical in comparison with commercial or industrial loads. Figure 1 shows typical domestic demand with different tariff [14].

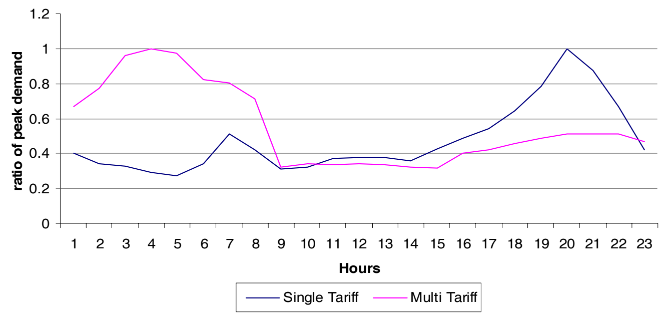

Fig 1. Different Domestic Demand Patterns

The first step to employ such demand responsiveness is to identify those loads which are capable to become responsive on a daily basis. Therefore by modeling the electrical appliances in domestic sector and evaluating their aggregated affect, the amount of dispatchable responsive demand will be quantified. Eelectricity is one of those services that demand for it is in fact by those services which are provided by electricity not electricity itself, unlike water. Therefore by knowing the electricity consumption of different appliances at each electricity sector and multiplying them by number of customers in each sector, the total electricity needed to supply those appliances can be forecasted [15]. Cold and wet appliances such as refregeration units and washing machine, water heating and space heating are those which could be considered to become responsive. This method can benefit electricity sector by providing the required data to monitor the electricity consumption of each electricity appliance in each sector; a piece of data which for energy reduction programmes and energy conservation is essential. Hereby we studied the energy consumption pattern of electrical appliances in domestic sector on daily basis.

The general equation to calculate the total daily power demand that is applicable to all end-use appliances is:

$$Di_t = N_i \times C_i \times Fi_t \tag{1}$$

$$Ei = \alpha . \sum_{t=0:00}^{t=23:59} Di_t \tag{2}$$

where:

Di_t is total power required by component i at time t;

N_i is the number of appliances of type i ;

C_i is load type i energy consumption (watt);

Fi_t is the fraction of the connected load of type i in at time t ;

Ei is the daily energy consumption of load type *i*.

As Fi_t in particular for domestic sector depend on type of day (weekday, Saturday, Sunday) another coefficient" α " needs to be multiplied to the equation (2) in order to differentiate the energy consumption of each appliance in different days[2]. Besides, N_i which represents the number of appliances of type *i* depends of socio-economic situation of each household. Therefore a comprehensive aggregated demand requires considering these modules as well.

The demand aggregation results are presented in Figure 2 and 3 which show different duty cycle of different types of load in domestic sector in two dissimilar load tariffs. Figure 2 represent Economy 7 when peak usually happens during the night and figure 3 is shows a single tariff system.

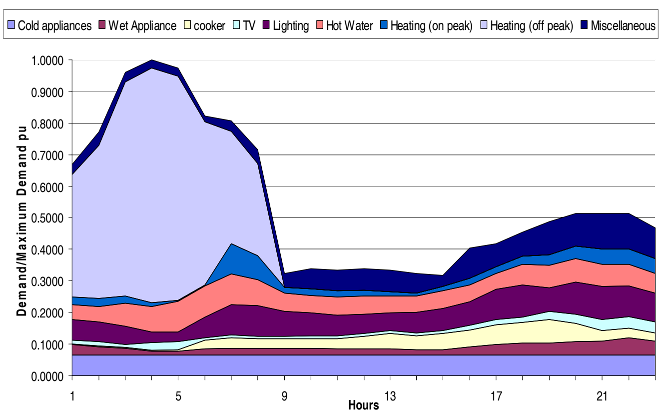

Fig 2. Multi Tariff Domestic Demand (Economy 7)

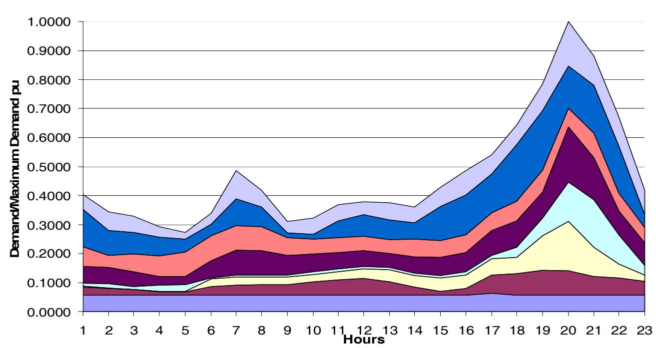

Fig 3. Single Tariff Domestic Demand

III. Assessment Tool

The aim of the Security Constrained Unit-Commitment (SCUC) problem is to find the hourly generation, reserves and price sensitive load schedule that minimizes the sum of energy costs, reserve costs and the negative of revenue from price-sensitive load over a twenty-four hour period subject to meeting all the network security constraints such as apparent power flow constraints, generator reactive power output constraints and voltage in busbars. SCUC is being considered more and more recently because Security of supply is one of the major concerns of network operators.

SCUC aims to minimize $C(c,e,s)$ and increase the security (through minimizing the security violation indexes) in a scheduling period with regarding to Production cost *"c"* ,Emissions *"e"* and Security violation index *"s":*

$$Min\, C(c,e,s) = (\sum_{i=1}^{N}[\tau c.\alpha c.c(Pi) + \tau e.\alpha e.e(Pi)] + \tau s.\alpha s.s) \quad (3)$$

A. Generation Cost:

Generation cost is a function of fuel cost, total start-up cost, shut-down cost and maintenances:

$$c(Pi) = FCi(Pi) + MCi(Pi) + STi(Pi) + SDi(Pi) \quad (4)$$

Fuel cost is

$$FCi\ (Pi) = ai\,.Pi^{2} + bi\,.Pi + ci \quad (5)$$

where ai , bi and ci are Cost coefficients.

Maintenance cost is a function of Base maintenance cost (*BMi*), and an incremental cost depending on output power:

$$MCi\ (Pi) = BMi + IMi\ .Pi \quad (6)$$

Total start-up cost (*STi)* is a function of turbine start-up cost *TSi* and the boiler Start-up cost *(BS*$_i$*) and number of hours that unit i has been down (D*$_i$*). For hours down* is (*AS*$_i$*)* is the boiler cool down coefficient:

$$STi = TSi + [1 - e^{(Di\ /\ ASi)}].\ BSi + MSi \quad (6)$$

Shut-down cost for each unit is a number depending on the output power of that unit. *K* is shut-down incremental cost

$$SDit = KPi \quad (7)$$

B. Emission:

Some of the pollutants produced by fossil fired plants in large quantities are sulphur dioxide SO_2, carbon dioxide CO_2, nitrogen oxides NO_x, hydrocarbons and coal fired plants also produce fly ash and metal traces. In this paper we have only considered NO_x emissions:

$$eij\ (Pi) = \alpha ij\,.Pi^{2} + \beta ijPi + \gamma ij + \delta ij\,.e^{\varepsilon ij\,.Pi} \quad (8)$$

where α , β , γ , δ , ε are the emission coefficients.

The total emission from each unit E_i can be calculated as the sum of individual pollutants:

$$E_i = \sum_{j=1}^{J} eij \quad (9)$$

where J is total number of pollutants considered in a dispatch.

C. Security:

The Security function consist of 3 main objectives; voltage at busbars, apparent power flow in branches and reactive power generated by generation units:

$$s = \tau v\,.sv + \tau b\,.sb + \tau g\,.sg \quad (10)$$

sv, sb and *sg* are voltage, apparent power flow and generator reactive power security violation indices and τv , τb and τg are the Boolean variable to either include these violation indices or not.

Voltage at busbars must always be set between a minimum and maximum limit at all the scheduled generation period.

[2] As end-use demand forecasting method requires continues data from end-use appliances, other demand coefficients such season are not included because it may be likely that an appliance type *i* has the same consumption pattern 2 similar days in a week but it is very unlikely that this pattern sustains in order to be extended for a whole season [16].

This could be done through generator voltage set point, transformer tap settings or reactive power control. The voltage rise due to installed windfarms at each busbar depends on the injected power:

$$\Delta V = \frac{P_{inj} \times R + Q_{inj} \times X}{V_s} \quad (11)$$

where ΔV represents the voltage deviation due to generation unit installed at that bus bur, and P_{inj} & Q_{inj} are active and reactive power injected from generation unit and R & X are line resistance and reactance and V_s is the nominal voltage .In SCUS calculations there is always a limit for ΔV; i.e. between 1.1-0.9pu of the nominal rate.

Apparent flow (Complex power; $S = P + jQ$) in transmission lines is one of the constraints which sometimes causes decomitting a unit or keeping its output up to certain level as transmission lines are running up to their maximum capacity; some thing which is known as transmission congestion.

In power systems voltage collapse usually happens when the reactive power is not enough to meet inductive loads such as induction motors etc. Generation units generate certain amount of reactive power and exceeding this limit will reduce the security of supply.

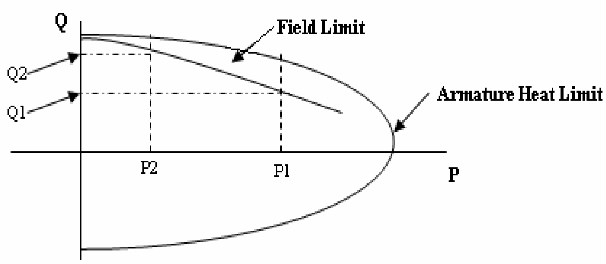

Fig 4. Generator Power Output Capability Graph.

Other constraints:

Apart from those mentioned objective constraints during unit-commitment, there are several other constraints which must be considered:

D. Crew constraints:

With thermal power plants, particularly starting up and shutting down generation units needs a certain number of crews to operate and sometimes because of lack of crews, it is impossible to start up or shut down more than one unit at a time.

E. Minimum up and down time:

In some plants i.e. nuclear, hydrothermal etc, because of economic efficiency and technical constraints it is impossible to shut down a unit before a certain duration of being in duty is reached; again once a unit is turned off it may be impossible to start it up and bring it back to network before certain number of hours of being off-duty is reached. These units have different characteristic than "Peaker" units; for instance gas turbine units which usually are not subject to a minimum up and down time and can start up and supply peak demand and shut down straight after peak period.

F. Generator output limits

Generation units must be scheduled to operate within their maximum and minimum rated output in terms of active (*PGi)* and reactive power (*QGi)*:

$$PGi\min \le PGi \le PGi\max \qquad QGi\min \le QGi \le QGi\max \quad (12)$$

G. Spinning Reserve

Total Generated power in the system must meet demand, network losses and required Spinning Reserve. Spinning reserve is the amount of power always available to be dispatched in the system to meet sudden demand increase or being used in minor contingencies.

$$\sum_{i=1}^{N} Pi \ge Demand + Network\ looses + Spinning\ reserve \quad (13)$$

$$\sum_{i=1}^{N} (CSPPi - Pi, SPi) \ge Spinning\ reserve \quad (14)$$

CSSPi is Capacity Limit of Unit i to provide Spinning Reserve and *SPi* is the Maximum contribution of unit i to spinning reserve.

H. Negative Reserve Requirement

Negative reserve is to make sure at each scheduling period there are sufficient generation units in the system which are running at certain amount higher than their minimum generation limits. This is to allow their output be reduced in case of loosing the demand in case of an event predicting it higher than actual value [17].

I. Generator Ramping Up and Ramping Down Rate

The ability to increase (or decrease) the output power of a generator in a certain amount of time is called Ramping Rate. Generation units have different ramping rates and this must be considered in unit-commitment. Ramping rate is particularly important for those units which are due to be committed to supply power reserve (especially spinning reserve) as certain amount of reserve is supposed to be generated by these units. Network operators i.e. NGC in the UK, have their own criteria for selecting units providing spinning reserve which in the UK is 25MW/minute within 2 minutes of instruction and to be sustained up to the minimum of 15 minutes [18].

J. Reliability Must Run Units (RMR)

In the power system generation units that the ISO determines are required to be on-line [at certain times] to meet applicable reliability criteria requirements [19]; such as voltage support or during system maintenances.

K. Regulatory Must Run Units (RGMR)

The main objective of regulatory must-run units is to maintain "fair" competition in a deregulated market. A good example of regulatory must-run units is hydro power plants. Most of these power plants are multipurpose units which were designed both for power generation and irrigation purposes. Allowing a hydropower plant to participate in the competitive market may defeat the agricultural purpose [19]. Another example of RGMR units exists in places where heat demand is added on top of electrical demand. In order to supply enough heat, we must make sure that enough thermal units (Combined Heat and Power CHP) which are supposed to provide heat in all heat demand areas are committed at each scheduling period.

L. Regulatory Must Take Units (RMTU)

In deregulated energy markets there are power purchase agreements (PPA) which occurred prior to the deregulation and carried over to the deregulated market. Examples of regulatory must-take units are nuclear power plants, cogenerations, and PPAs with other entities such as neighboring countries. It means in OPF, ED and UC calculations these PPAs also need to be considered [19].

M. Qualified Unit Providing Ancillary Services in Deregulated Energy Market

Ancillary services usually are provided by specific units. In deregulated energy market where price bidding exists both for power and ancillary services, not all the generation units can participate in providing ancillary services. At each period some power utilities which normally participate in providing ancillary services may or may not be available.

N. Balance between Demand and Power in Deregulated Energy Market

In a deregulated Energy market (DEG), network operators particularly those who provide ancillary services such as spinning reserve or operating reserve, are allowed to either supply an extra power into grid or by reducing the demand to reduce the need of an extra reserve. This is a new term in DEG which has been using in some parts of the world [14]. Therefore by committing those companies which are allowed to shed the load to unrequire the network to extra power, in fact the demand which needs to be supplied is being reduced and network parameters must be studied well before committing generation units as it may cause voltage rise in the system because of extra power which is not being consumed. There are also other ways such as pump storages, interchange etc. All the power which is due to be achieved from these sources must be subtracted from total required reserve [17].

IV. Implementation

The IEEE Standard 30 Bus Test System [22] has been chosen for our project. Figure 4 shows the proposed network, the main objective of our research is to integrate responsive demand into the system, after running the simulation without the presence of responsive demand, those appliances in domestic sector which were capable to become responsive have been selected to act as responsive demand and they respond to output of wind generators. In the network there are different types of generators; coal fired, gas fired and wind generators. Table 1 shows the generators cost and emissions characteristics and Table 2 shows Minimum Up Time (MUT), Minimum Down Time (MDT), Ramp rate, Minimum and Maximum power output and locations of conventional plants. All generators data apart from generator No. 9, 10 and 11 are derived from IEEE Reliability Test System RTS-96[23].

Total conventional plants capacity is 300MW while 2 windfarms have 15MW (windfarm No.1 capacity factor = 26%) and 20MW (Windfarm No.2 capacity factor = 29%) installed capacity. Figure 6 shows weekly output of two windfarms. These 2 windfarms were placed on bus number 24. As shown in figure 5 in different locations different types of demand exist. It is assumed that responsive demand is only available in domestic sector and their mode of responding to the network depends on output of windfarms.

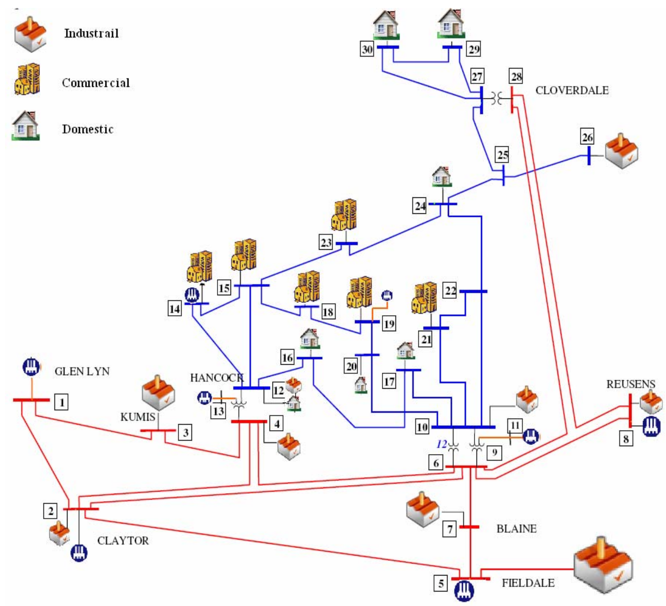

Fig 5. The IEEE 30 Bus Test System with different types of demand

TABLE I.
GENERATOR COST AND NOx EMISSION CHARACTERISTICS

Unit	a	b	c	α	β	γ	δ	ε
1	0.02	1.2	40	9.9E-2	-5.6E-2	4.1E-2	1.5E-4	3.86
2	0.01	0.8	38	5.6E-2	-6.1E-2	4.8E-2	1.0E-4	3.3
3	0.06	4.5	45	7.6E-2	-5.1E-2	2.6E-2	1.0E-8	8.0
4	0.01	0.4	30	3.4E-2	-3.6E-2	5.3E-2	1.0E-6	2.0
5	0.06	5.2	23	3.5E-1	-5.1E-2	2.3E-2	1.0E-8	8.0
6	0.05	2.2	42	4.4E-2	-5.1E-2	3.4E-2	1.0E-8	8.0
7	0.05	3.0	45	1.8E-1	-5.1E-2	2.9E-2	1.0E-8	8.0
8	0.04	1.8	53	5.2E-2	-9.5E-4	3.1E-2	2.3E-4	6.67
9	0.00	0.0	0	0E+0	0E+0	0E+0	0E+0	0.0
10	0.00	0.0	0	0E+0	0E+0	0E+0	0E+0	0.0

TABLE II.
OTHER GENERATORS CHARACTERISTICS

Unit	MUT	MDT	Ramp Rate	P*min*	P*max*	Busbar No.
1	3	2	5	10	35	11
2	2	2	4	10	45	5
3	3	2	7	8	40	2
4	3	2	6	10	60	1
5	1	1	6	5	25	19
6	2	1	5	2	30	14
7	2	2	7	5	35	8
8	2	1	4	5	30	13
9	0	0	4	0	10	24
10	0	0	4	0	15	24

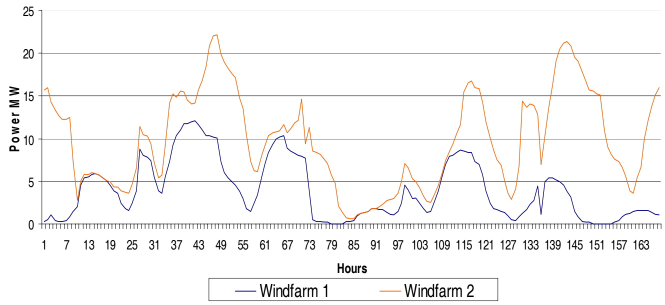

Fig 6. Weekly output variations of Wind farms [24]

V. RESULTS

A. Production Cost

Total generation cost; which is total running cost of conventional plants, is significantly differs in presence of responsive demand. Without responsive demand whenever wind output drops conventional plants needs to supply the demand. As result of intermittency these fluctuations may happen at any time and the magnitude and speed of these fluctuations usually obliges network operators to utilize those units which could be utilized free of constraints such as a long uptime or down time. These units are usually OCGTs which are very expensive to run and the difference in cost at each case is because of reducing the need for running these units. Table III shows the result of our simulation for each case. We have considered several cases; first when there is no demand side management program is implemented and the results show generation cost is $85228.3, By having 16% multi-tariff demand the generation cost will reduce by 1.3% down to $84057.69 . 1.3% drop in generation cost in a network with total 300MW demand may not be noticeable but in a real network this reduction is significant. After introducing responsive demand in the network this reduction is more significant and total generation cost for single rate with responsive demand and economy 7 with responsive demand will be respectively $84032.73 and $82414.13.

B. Security Index

As mentioned in section III security violation index consists of three main objectives; voltage in busbars, reactive power of generators and active power flow over transmission lines. Any of these factors if violate over their limits it makes the unit-commitment and economic dispatch decisions unacceptable. Security violation indices are calculated by following equations:

$$sv = \sum_{i=1}^{I} (\left|V_i^{ideal} - V_i\right| - V_i^{\partial})^2 \ if \ (V_i^{ideal} - V_i) > V_i^{\partial} \quad (15)$$

$$sb = \sum_{k=1}^{K} (\left|S_k^{\max} - S_k\right| - S_k^{\partial})^2 \ if \ (S_k^{\max} - S_k) > S_k^{\partial} \quad (16)$$

$$sg = \sum_{m=1}^{M} (\left|Q_m^{\max} - Q_m\right| - Q_m^{\partial})^2 \ if \ (Q_m^{\max} - Q_m) > Q_m^{\partial} \quad (17)$$

where *I*, *K* and *M* are the numbers of bus bars, branches and generating units respectively. V_i , S_k and Q_m are voltage at bus *i*, apparent power flow in branch *k* and reactive power generated by unit *m*. The *ideal* superscript denotes the desired value of the respective variable and the *max* superscript denotes the rated value while the ∂ superscript denotes the tolerance allowed for the variable, which is the maximum deviation allowed from the desired or rated value.

The results for security index show it is 29.699, by having 16% multi-tariff demand it will be down to 28.451. After introducing responsive demand in the network security index for single rate with responsive demand and economy 7 with responsive demand will be respectively 27.940 and 23.850 representing more secure network.

C. Emissions

Emissions which all come from conventional units are calculated in this simulation. As we expected in the worst scenario where there is no demand management in the network we see the highest level of emission. Demand side managements significantly reduce the emissions as it is noticeable in table 3. 1.3 tones of NO_x emissions could be reduced just by multi tariff load. While this number can be further more up to 2.15 tones if responsive demand is mixed with economy 7 tariff.

TABLE III
POWER SYSTEM OPERATIONAL PARAMETERS RESULTS

Case	Production Cost *$*	Security *Index*	Emission *Tones*
Single rate	$85228.30	29.699	27.99547
16% Domestic Economy 7	$84457.69	28.451	26. 63810
Single rate with Res. Demand	$84032.73	27.940	26.05713
16% Domestic Economy 7 with Res. Demand	$82414.13	23.850	25.84281

D. Value of wind

Value of wind is defined in equation below [25]:

$$Value\ of\ Wind = \frac{C(No\ wind) - C(with\ wind)}{P(Wind)} \ \$/_{MW} \qquad (18)$$

Where C is total production cost and P represents the installed wind capacity in MW.

Value of wind shows how much money could be saved through in supplying the demand per MW installed wind capacity.

By increasing the wind penetration as the power injected to the network through wind will reduce the need for running conventional plants, therefore total production cost is cheaper in general with increasing the wind penetration. However this is not always the case as network constraints such as busbar voltage rise where windfarms are installed, and the UC decisions may change and total production may increase. This increase may happen at certain penetrations where local demand still needs to be fed by other plants or at certain locations where transmission system connected to the network is not able to transport the power comes from renewables. This is one of our findings in bus No.24.

There are several solutions to rectify these problems as mentioned before in section I. Our proposed method is based on involving demand to respond to some objectives:

1. wind generator output variations;
2. busbar Voltage rise or drop;
3. power flow congestion known as Transmission Congestion.

These are the areas which demand can respond in a way to maximize the utilization of renewables. In this project so far we have just considered the wind generator variations and demand can respond to these variations, by any mean which demand can be responsive; such as communication between loads and network or detecting these variations in demand side autonomously. However we have only considered shedding the load in case wind power output drops below certain level. This level is 10MW when 15% of total domestic loads will respond to it and in fact negative load will increase the value of wind and the amount of available responsive demand differs for single and economy 7 tariffs.

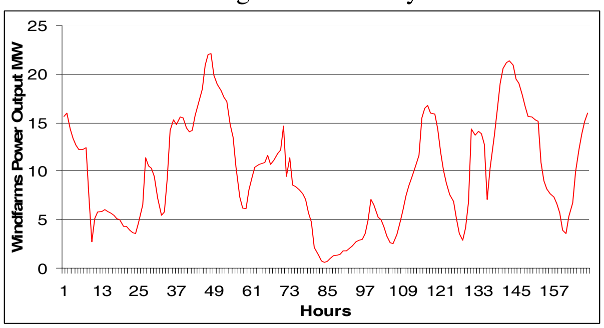

Fig 7. Windfarms Power Output

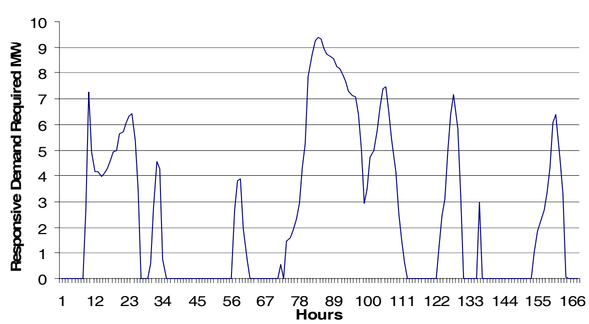

Fig 8. The Shortfall of Windfarms output to 10MW

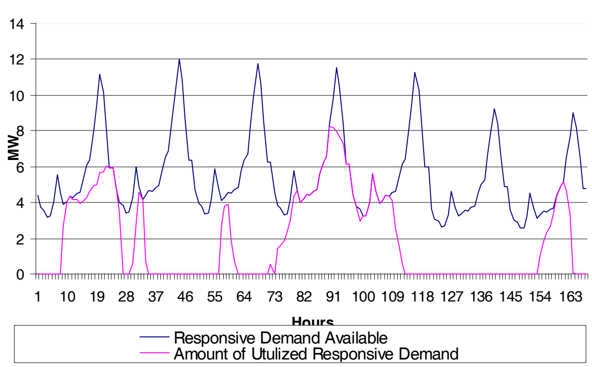

Fig 9. Amount of Available and Utilized Responsive Demand for Single tariff Demand

Currently several techniques are available so as to achieve responsive demand. These techniques are mostly price based. Techniques such as Real-Time Pricing (RTP), Time of Use Pricing (TUP) or Critical Peak Pricing (CPP) all require demand responsiveness to respond to electricity price changes [7].

The proposed method is suitable for islanded networks where price is not the main issue but reliability and increasing the independency to external power is the final goal. The calculation of requited responsive demand is done according to following algorithm:

$$RD_t = Pm - Pw_t \tag{16}$$

where RD_t is required responsive demand at time *t*, Pm is the final goal power which in this paper is set to 10MW and Pw_t is output of intermittent generators at the time *t*.

The total generation cost without wind in our system was calculated $96444.22. As 35MW of total wind capacity is installed in the network value wind for each case is calculated according to equation 14.

TABLE IV.
VALUE OF WIND IN DIFFERENT DSM PROGRAMS

Case	Value of Wind $/MW. Week
Single Rate with 10% Wind Penetration	320.4
Economy 7 with 10% Wind	342.4
Single Rate with Responsive Demand and 10% Wind Penetration	354.6
Economy 7 with Responsive Demand and 10% Wind Penetration	400.8

The results unsurprisingly show the increase of value of wind in presence of demand side management programs. When value of wind is greater, it means the network needs to use the conventional plants less to serve the demand and in fact it is more *“Sustainable”* electricity generation network.

VI. CONCLUSIONS

In this paper the aggregation technique to evaluate the amount of dispatchable responsiveness demand with different load tariffs, has been demonstrated. Then by applying different load tariffs into a network while renewables (wind here in this case) have high penetration, the power system operational parameters are quantified first. Subsequently responsive demand has been combined with other loads and those concerned parameters are re-evaluated. The algorithm to determine the responsive demand is based on output of windfarms here as it aims to increase the value of wind ultimately.

The results clearly show the benefits which could be achieved from DSM programs. Besides, having responsive demand in the network regardless of integration cost and the value of lost load through shedding the demand, will improve these parameters; results in lower cost and emission, higher security and increases the value of wind.

VII. References

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